ORIGINAL

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BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP, CHAIRMAN
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

Docket No. E-01933A-12-0291

NOTICE OF FILING DIRECT TESTIMONY OF RICK GILLIAM ON BEHALF OF THE VOTE SOLAR INITIATIVE

The Vote Solar Initiative ("VSI"), through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony of Rick Gilliam related to cost of service and rate design.

RESPECTFULLY SUBMITTED this 11th day of January, 2013.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By ______________________
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ORIGINAL and 13 COPIES of the foregoing filed this 11th day of January, 2013, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing Electronically mailed this 11th day of January, 2013 to:

All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-12-0291

DIRECT TESTIMONY OF RICK GILLIAM

ON BEHALF OF THE VOTE SOLAR INITIATIVE

JANUARY 11, 2013

Introduction

Q. Please state your name and business address.

A. My name is Rick Gilliam. My business address is 1120 Pearl Street, Suite 200 in Boulder, Colorado.

Q. On whose behalf are you submitting this rebuttal testimony?

A. This testimony is submitted on behalf of The Vote Solar Initiative ("Vote Solar").

Q. By whom are you employed and in what capacity?

A. I serve as Director of Research and Analysis for Vote Solar, and oversee policy initiatives, development, and implementation.

Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement the key policies needed to integrate solar into the marketplace. We have nearly 2,500 Arizona members with 269 within TEP's service territory.

Q. Please describe your experience in utility regulatory matters.

A. Prior to joining Vote Solar in January of 2012, my regulatory experience included five years in the Government Affairs group at Sun Edison, one of the world's largest solar developers, twelve years at Public Service Company of Colorado (PSCo or the Company) as Director of Revenue Requirements and twelve years with Western Resource Advocates (WRA – formerly known as the Land and Water Fund of the Rockies or LAW Fund) as Senior Policy Advisor. Prior to that, I spent six years with the Federal Energy Regulatory Commission. All told, I have in excess of 30 years of experience in utility regulatory matters. A summary of my background is attached as Appendix A.

Q. Have you previously testified before the Arizona Corporation Commission ("ACC" or "Commission")?

A. Yes. I testified before this Commission on behalf of the LAW Fund in some of the early proceedings regarding the development of a renewable standard, and have participated in a number of rulemakings in the intervening period.

Q. Before what other utility regulatory commissions have you testified?

A. I have testified in proceedings before the Public Utilities Commission of Colorado, Nevada Public Utilities Commission, the New Mexico Public

Regulation Commission, the Utah Public Service Commission, the Wyoming Public Service Commission and the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Arizona Corporation Commission (ACC) with Vote Solar's perspective on how the the cost recovery and rate design proposals of Tucson Electric Power (TEP) may affect current solar customers and future solar adopters in TEP's service area.

Q. Please summarize your testimony.

A. Utilities across the country, including TEP, are experiencing major changes and shifts in the way customers use energy. Growth in retail sales on an aggregate basis, is slowing across the U.S., due largely to reduced economic activity coupled with increased deployment of demand side management technologies and distributed generation resources. According to the U.S. Energy Information Administration (EIA), total delivered electricity use in all sectors is predicted to increase at an annual growth rate of 0.7 percent per year from 2010 through the year 2035.[1] Furthermore, The EIA projects that both distributed generation solar (DG solar) and microturbine electric generation additions between 2010 and

[1] Faruqui, Ahmad and Eric Shultz. "Demand Growth and the New Normal: Five forces are putting the squeeze on electricity consumption" Public Utilities Fortnightly, December 2012; < http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal/page/0/1?authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98>.

2035 will outpace the growth in conventional natural gas-fired cogeneration, wind, and fuel cells.[2] TEP is not immune to these meta changes, being felt by utilities across the nation. TEP like many utilities is seeking incremental changes in certain aspects of their business model to cope with a changing energy landscape. In this proceeding, TEP is proposing a number of structural changes to its retail rates in an effort to reduce the uncertainty and improve the stability of revenue recovery related to electric sales. In this testimony, I address three of those changes that will affect DG solar customers: the proposed increase to the monthly customer charges; the proposed increase in the demand ratchet for certain customer classes to 100%; and the Lost Fixed Cost Recovery Mechanism.

Q. Please characterize Vote Solar's interest in this TEP rate case.

A. A sizable amount of Vote Solar's work is focused on rate design issues related to distributed generation (DG) solar. Vote Solar is actively participating in net metering and broader rate design regulatory proceedings in states across the U.S, including: Arizona, California, Colorado, Minnesota, New Mexico, New York and Vermont among others. Our interest in this case is as follows: TEP's proposals in this rate case indicate that the utility is restructuring its rate design to account for higher penetrations of DG solar, and other energy reducing technologies. We believe TEP, and this proceeding, will establish new

[2] Ibid.

ratemaking concepts that other utilities may wish to follow. The trends experienced by TEP as outlined by TEP witnesses are not unique to TEP but rather point to over-arching shifts in the national utility landscape. Thus the outcome of this rate case has implications beyond Tucson and Southern Arizona, and we want to ensure that the decisions made in this rate case do not harm the potential for DG solar to play an increasingly large role in the TEP service area, or even the national landscape. Trends highlighted in this case include:

- Reduced sales growth: As a result of many different factors including the economic recession, increased customer efficiency, increased self-generation, the growth in sales is projected to be below historical norms.
- Increased cost growth: Additional costs are being incurred by TEP to serve its customer base, both in terms of investments and increased cost of operations, regardless of the amount of sales growth anticipated;
- Increased environmental concern: in the wake of hurricane Sandy, and Irene and Lee before it, there is increased awareness and concern about the effects of climate change. There could soon be additional federal pressure to reduce carbon emissions, including reducing emissions from its conventional coal burning fleet of generators.
- Increased consumer preference for clean resources: there is great popular support for increasing the amount of clean energy in the mix of resources used to generate electricity in TEP's service area in Arizona, and even nationwide.

Commissions are rightly concerned about the effect of these trends on the retail electric rates that customers will be asked to pay. In this proceeding, there are certain rate proposals that represent changes to TEP's cost recovery mechanisms, which would impact the ability of TEP's retail customers to install solar on their homes and businesses. It is these changes that specifically interest Vote Solar.

Q. Please describe some of the popular support for clean renewable resources in Arizona.

A. According to an article in the Arizona Journal on September 19 of this year,."four separate public opinion surveys conducted in May 2011 by APS and the Morrison Institute for Public Policy revealed that 94% of APS customers support increasing the use of solar energy." In TEP's service territory, a utility-conducted poll found that 73% of respondents agreed or strongly agreed that "it is important TEP uses all types of renewable resources including solar, wind, geothermal, hydroelectric, biomass and biogas, to provide energy to their customers." Additionally, 74% agreed or strongly agreed that; "it is important TEP uses solar power as the primary renewable resource to meet its renewable energy requirement."

Q. What is TEP's view of the effect of recent economic conditions?

A. In response to discovery, TEP stated as follows:

> "TEP believes that the weak economic conditions that have existed for the last several years have contributed to load and sales reductions. These conditions have created residential and commercial vacancies and caused individuals and businesses to look for new ways to keep down their costs. TEP believes that these cost reduction efforts include conserving their utilization of electricity, and thus impact sales. However, TEP does not have any specific studies to estimate the magnitude of impact that the economic downturn has had on sales."[3]

Q. Can the effect on electricity sales of the recession be estimated?

A. Yes. By comparing actual pre-recession sales growth rates with growth rates in-recession and accounting for sales reduction related to efficiency and distributed generation, the effect of economic conditions over the last five years can be estimated.

2000-2007 growth rate	2.3%	TEP/Bonavia, p. 6
2007 Retail Sales	9,634 GWh	2007 Form 1
Estimated 2011 sales with pre-recession growth rate applied	10,551 GWh	
Actual 2011 Sales	9,332 GWh	2011 Form 1
Estimated total sales reductions	1,219 GWh	
2011 sales reductions related to EE	66 GWh	TEP/Bonavia, p. 7
2011 sales reductions related to DG	89 GWh	TEP/Bonavia, p. 7
Estimated sales reduction effect of economic conditions	1,064 GWh	

[3] TEP response to VSI 1.22

From this "back of the envelope" analysis, it is clear that sales reductions related to energy efficiency programs and distributed generation are minor compared to those related to economic conditions – only 5% and 7% respectively. This analysis also does not take normal weather into account. The cooling degree days in 2011 (both for that year and on a ten year rolling average basis) are higher than those in 2007, the implication being that hotter than normal weather helped to increase sales in 2011.

Q. Should the level of sales growth remain very low to zero as a result of the aforementioned factors, would there be some constant level of costs to provide electric utility service that can be achieved?

A. It doesn't appear so. There are certain costs that will continue to increase:

"Given the need to replace components of the infrastructure costs increase because of the replacement of fully depreciated capital items with new equipment that has higher costs just because of inflation. Further, the assumption of constant load does not mean that new investment to connect new customers is not occurring. This new investment costs more than the average cost included in rates. Constantly changing environmental regulations require the investment in new facilities to meet those requirements. The net result is increased rate base and thus higher revenue requirements to support capital. In addition, expenses also increase over time due to a variety of factors such as inflation, government mandates and other factors beyond the reasonable control of the utility such as healthcare costs, postage, taxes and so forth.[4]

[4] TEP response to VSI 2.21

In summary, TEP indicates "*constant, or flat, electric sales over five years do not translate equally to flat capital investments or flat O&M expenses.*"[5]

Q. Do you have examples of cost increases since the last rate settlement?

A. Yes. TEP noted the following major O&M increases between 2006 and 2011:[6]

Payroll:	$ 6.8 million
Overhaul and outage normalized expenses:	$ 6.3 million
Pension costs:	$ 4.6 million
Transmission cost:	$ 5.9 million
Outside Services:	$ 4.1 million
Total	**$27.7 million**

While one would hope that some steady state level of expenses (including return on assets) could be reached for a static level of sales, current experience appears to run counter to this ideal.

Q. What are the implications of these cost increases combined with the sales reductions that TEP describes?

A. Recent sales reductions due to a variety of causes puts significant pressure on TEP's ability to maintain its desired earnings levels, especially in an environment where costs continue to increase. It's difficult to predict, for example, what the new "normal" level of sales growth will be over the longer term when the

[5] TEP response to VSI 1.38 (see also VSI 1.07)
[6] TEP response to RUCO 2.04

economy recovers, compounded by the question of whether the extreme weather experienced during the test period is the new *normal*. However, if the normal level of sales growth is substantially less than the 2.3% that TEP enjoyed pre-recession and costs continue to grow, the unavoidable result is a series of significant rate increases under the traditional regulatory model.

Q. Is there any way to estimate future potential rate increases?

A. There are many variables that impact the costs of providing electric service, however the current increase request could be representative of future increases if current conditions persist. Indeed, capital additions are expected to increase over the next five years to a level about 50% higher than those of the last five years.[7]

Q. What factors might cause TEP to have increased sales, offsetting recent historical trends?

A. Sales can increase as a result of a revitalized economy (both electricity use per customer and number of customers), new "must-have" home appliances such as plasma screen TVs, and importantly, increased penetration of electric vehicles. Additionally, increasing frequency of extreme weather will cause increased use of air conditioning equipment, and hence sales will likely increase. While the 2011

[7] See TEP witness Larson Direct Testimony, page 13, lines 6-8.

test year may be "extreme" in terms of cooling degree days when compared to a ten-year average, it may in fact represent the new normal. Each of these changes would increase sales from test year levels and result in margin improvement for TEP.

Q. How is TEP proposing to deal with these trends?

A. In its Application and subsequent discovery, TEP describes its efforts to manage its costs, but there is no real strategic change in operational direction discernable in this rate filing by TEP. TEP witness DesLauriers suggests that the challenging operating conditions including the economy, regulatory requirements, and effect of new technologies, will impact TEP over the near and medium terms.[8] TEP continues to operate itself under essentially the same traditional business and regulatory model virtually all regulated utilities have used for decades. It does however seek several new rate mechanisms to provide quicker and more stable recovery of its costs as a means of reducing earnings uncertainty related to conventional retail electric service in this changing world. In other words, TEP is not addressing the underlying structural changes but rather some of the symptoms.

[8] Direct Testimony pages 10-13; note that near and medium terms are undefined.

In addition to the conventional adjustments to its test year for in-period and post-period changes, TEP is proposing a number of changes in its revenue recovery strategies that would increase the certainty of it recovering certain perceived revenue shortfalls including:

- Transferring recovery of certain demand-related costs from the existing mechanism (sales or demand-based, depending on class) to the flat monthly customer charge;
- Modifying the existing 50% or 66% C&I demand ratchet to a 100% ratchet;
- Imposition of a limited decoupling mechanism known as the LFCR applicable to all rate classes other than water pumping and lighting; and
- Imposition of a rate rider mechanism to recover capital and operating costs related to environmental controls on existing coal plants.

Given the changing world TEP itself describes, in order to avoid a long series of rate increases, we believe the Company and the Commission should begin consideration of new paradigms of utility and regulatory operations in which sales growth is minimal, capital investment is limited to connecting new customers and replacing worn out assets, and expense growth is related primarily to inflationary levels. Minimizing significant capital additions in the future reduces the risk of future non-maintenance related stranded assets.

Q. What should TEP be considering?

A. TEP is among the first utilities addressing this changing world in the near term. Indeed, a recent report[9] from the Deloitte Center for Energy Solutions – *The math does not lie: Factoring the future of the US electric power industry* - addresses these very issues and concludes electric companies should rethink their strategies, and consider options that include very strict management of the "numerator," i.e. the cost side of the equation, new regulatory structures and initiatives, development of new regulated revenue streams, and consideration of innovative business models and non-regulated business expansion.

Q. Is TEP moving in this direction in this proceeding?

A. Yes, it is to an extent. TEP describes in its testimony its cost management efforts. Additionally, TEP proposes a partial decoupling mechanism providing a new rate recovery structure that begins to address future sales uncertainty. In addition, implementation of the Smart Grid, initially through meter upgrades, will provide additional information about customer behavior and effects on the grid providing the potential for more efficient operations. However, TEP's investment in smart meter deployment represents only about 1.3% of total regulated investments over the last four years. The following chart provides the status of smart meter deployment.

[9] See http://www.deloitte.com/view/en_US/us/Industries/power-utilities/24d2878b0898a310VgnVCM2000003356f70aRCRD.htm

Deployment of "Smart" Meters[10]	Interval Meters	% of Total	Projected Completion[11]
Residential	112,119	29%	6 years
Commercial	16,276	42%	5 years
Industrial	108	100%	Complete
Distribution Feeders	277	68%	Complete[12]

The problem we have today is that we simply don't know how persistent current conditions will be, and how they may change in the future. TEP should be commended for moving in this direction and encouraged to build out its advanced metering infrastructure to provide increased transparency and data availability to further improve opportunities for increased efficiency in operations, and to help develop more effective rates and cost recovery mechanisms in the future.

Q. Do you have concerns with any of the new proposals set forth by TEP in this proceeding?

A. Yes. I will address three proposals – the increase in the monthly customer charge, the increase in the demand ratchet, and the partial decoupling mechanism.

[10] TEP response to VSI 2.02.
[11] TEP response to VSI 3.02
[12] Ibid, TEP indicates "The remaining 131 feeders have meters that provide the data needed at this time. There are no plans to replace any of the remaining 131 meters with Smart Meters."

Proposed Increase to Monthly Customer Charge

Q. Please describe the change to the customer charge proposed by TEP.

A. For virtually all rate classes, including those with demand-based charges, TEP is proposing to recover a portion of demand-related costs through the monthly customer charge, aka service and facilities charge, to remedy revenue instability.

Q. Is this a common practice for the recovery of non-customer-related costs?

A. Generally not. Common practice is to recover costs incurred by the sheer existence of an individual customer in the customer charge. This would include costs such as meters, meter-reading, billing and collection, and so forth. These are costs caused by the number of customers being served independent of the consumption or power demands of the individual customers. Other non-customer related costs of providing service are generally recovered on a volumetric basis either on the volume of kWh or kW depending on class.

Q. Why is TEP proposing this change?

A. TEP is concerned that "if customer usage falls, the Company will not have a reasonable opportunity to earn its authorized rate of return."[13] Additionally, TEP states that higher load factor customers pay a disproportionate share of the system costs under the current rate structure, and that this shift will help to

[13] TEP witness Jones Direct Testimony, page 29, lines 14-16

relieve that burden. *"If the Company can shift revenue collection away from energy charges, it can reduce the cross-subsidization that occurs when usage within customer classes varies significantly."*[14]

Q. What is your understanding of the term "cross-subsidization?"

A. A subsidy is created when the actual cost to serve a retail electric customer is different than the costs being recovered from that customer by the utility. Anytime the costs recovered from a customer, or from a class of customers, are different from the amount allocated or assigned to them during the previous rate case, a subsidy is theoretically created.

This can become a complex equation as the cost allocation process to assign class cost responsibility is inherently non-precise. This is further complicated because customers and customer classes tend not to be static, but to change usage and demand patterns over time. Thus, as soon as new rates are placed into effect, cross subsidization will begin to occur with some customers paying more and some less than their up-to-the-minute theoretically appropriate cost of service, were one to be performed at that point in time. A ready example is the diverse rates of return (and hence revenue requirements) by customer classes experienced by TEP as noted by TEP witness Jones: the Company's class cost

[14] TEP witness Jones Direct Testimony, page 31, lines 11-13.

of service study "shows that the residential and large light & power customers are being subsidized by the general service class."[15]

In an ideal non-subsidized world, each customer class would be assigned its precise cost responsibility, provide revenue equal to its allocated costs, and each customer within the class would be at the exact mean for the class. Alternatively, a full cost of service study could be performed for each and every customer. As neither option is realistic, we should recognize and acknowledge that the estimates and approximations made for the sake of administrative ease yield results assumed to be just and reasonable without straying into the bounds of "undue discrimination."

Q. Do you have concerns with the TEP proposal?

A. Yes. First, it is important to remember that changes in sales can occur in both directions, as outlined above. The sales reduction impacts of the recession have laid bare a downside for the utility of the current structure, i.e. recovering costs on a basis that is different from the causation of the cost. Conversely, increases in sales between rate cases such as those that result from weather warmer than "normal" (in a rate case context) will result in the potential for the utility to earn in excess of its authorized return. This structure results from a regulatory balance

[15] Direct Testimony, page 4, lines 9-10.

that has evolved over many years and departure should be made carefully and thoughtfully.

Second, an increased flat monthly unavoidable customer charge, coupled with lower marginal energy costs reduces the incentive for a customer to be more efficient with its energy use. It does not promote conservation as suggested by TEP.[16]

Third, TEP is not suggesting that certain *specific* costs be moved from recovery through the variable rate to the monthly flat customer charge. It is suggesting that the customer charge be increased by seemingly arbitrary amounts not tied to specific costs, but rather as a matter of policy and revenue stability. Further, the testimony of its witness Jones suggests that it will continue moving towards full non-fuel cost recovery in the monthly customer charge for customers on volumetric rates (see generally Jones Direct testimony, page 33), known as a "straight fixed-variable" rate structure. TEP should be required to demonstrate, and the Commission approve, the nature of any specific costs sought to be recovered through a customer charge, that clearly shows that such costs are more closely related to the existence of the customer than to the consumption (size) of the customer.

[16] TEP response to VSI 2.25: "Importantly, the change in cost recovery moves to more economically efficient rates that allow the customer to know the real economic value of conservation as opposed to a value that overstates the savings from conservation and results in higher rates for all customers."

Fourth, TEP's purported goal is to reduce a cross subsidy between high and low load factor customers. However, this change simply establishes a different cross subsidization whereby everyone pays for a portion of fixed costs on a flat monthly basis regardless of the fixed costs required to serve the customer. In the extreme, TEP's straight fixed-variable rate structure would charge every customer in a class, regardless of size, the very same amount for demand-related costs, resulting in a fuel-only variable charge in the 3-4 cent range per kWh, and a monthly customer charge of $55 for residential and $362 for the Small General Service class.[17] This approach would impose a significant cost burden on small customers and a major subsidization of larger customers within the class.

Finally, the claim that higher load factor customers pay a disproportionate amount of system costs is based on an assumption that the amount that customers pay for electric service is the precise cost of serving them individually. This is simply not true.

Q. Why do you say that rates are not precise?

[17] From workpapers: 2012 Schedule G 12-31-11 (Revised 10-05-12); Sheet G-6-1 Unit Cost.

A. In regulatory circles, it is often said that ratemaking is an art, not a science. The process of determining revenue requirements, classifying and allocating costs, and designing rates is full of assumptions, estimates, modeled data, statistical methods, and adjustments made in a legitimate effort to spread cost responsibility to customer classes based on causation, and achieve a reasonably consistent relationship between costs and revenue so that the utility can have an opportunity to recover its costs and earn its authorized return on equity between rate cases. Moreover, even accepting all the approximations in the process, the rate for a class is designed for that mythical customer that represents the weighted mean of the group. This is not intended to be an indictment of the regulatory system - there are very good reasons why the process has evolved to the current structure. However, as we start to make selective changes that move away from current structures and practices, we should carefully examine the bases for doing so and the consequences.

Q. Please elaborate.

A. As described by TEP, rates are the result of a multi-step process of functionalizing costs, classifying costs, and allocating costs to customer classes. Each step is designed to group expenses (including a weighted return on rate base) into categories with similar cost incurrence characteristics for later allocation. In the end, there are only three things about a customer that can be measured and thus billed – (1) the customer exists, (2) the amount of energy the customer consumes in a billing period, and (3) the maximum amount of energy that customer uses in a defined period (usually 15 minutes). The third item is sometimes tracked for every 15-minute period throughout the billing period for large customers and those on certain rate forms that differentiate demand charges by time of day. As a result, all utility costs must be recovered on the basis of one, or a combination, of these three parameters.

Conveniently, costs are generally incurred because (1) customers exist, (2) electricity must be generated to be consumed each hour of each day, and (3) sufficient capacity must be available to serve the maximum load imposed on the system, plus a reserve margin.

The principle of cost responsibility related to cost causation is a basic underlying principle of utility ratemaking. This is noted by TEP witness Jones on page 17 of his direct testimony:

> *The allocation factor should be based upon an equitable method that harmonizes the cost-causation with the functional cost being considered. In other words, the allocation should be done in a way where the cost-causation for the functional cost considered is properly identified.*

And also in response to Vote Solar discovery question 2.03:

> *Given the load characteristics of each class of service (class coincident peak and class load factor) different methods will allocate more or less costs to each class of service. The appropriate cost allocation method is*

> *the one that most clearly recognizes cost causation based on the operating, planning and system characteristics of the utility. Accordingly, TEP believes that the Average and Peaks method is most suitable.*

Drawing heavily on the criteria of a sound rate structure developed by Bonbright in Principles of Public Utility Rates,[18] TEP witness DesLauriers confirms the importance of cost causation (page 14):

> *Rate Equity & Non-Discrimination – This concept requires that prices should be designed to be just and reasonable and avoid undue discrimination. Having rates that reflect cost causation and the recovery of costs that arise from customers taking utility service promotes equity and non-discrimination.*

Similarly, the "NARUC Electric Utility Cost Allocation Manual" (NARUC, 1992) begins its description of the design of rates as follows:

> *Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant.*

It should be clear that cost causation and cost recovery are regulatorily "joined at the hip."

Q. How does cost causation affect this cost recovery issue?

A. There is sometimes a tension between cost causation and the means of cost recovery. For some costs incurred by utilities, the causation and recovery are very well aligned – a good example being fuel costs. Another example of good alignment is the cost related to an individual customer – metering, billing, etc.

[18] Bonbright, James, Principles of Public Utility Rates, Public Utilities Reports, Inc., 1988

Other costs are not so well aligned and require judgment. For example, non-fuel production costs (representing the largest portion - about 59% - of total non-fuel costs) and transmission costs (about 20% of total non-fuel costs) are allocated to customer classes based on the Average and Peaks method in which a portion of the costs are assigned on average customer class demand (also known as energy consumption) and the remainder on the class's contribution to the four monthly summer peaks. In TEP's words, "The Average and Peaks method recognizes the importance of the role of energy use in optimal system planning." Further, TEP addresses the cost causation relationship as follows: "The Company's average and peaks approach recognizes that plant is not just built to serve demand, but also to supply energy."[19] Moreover, the other component of the "Average and Peaks" method assigns costs to customer classes based on each customer class's *contribution* to the relevant system peaks – in TEP's case an average of the four monthly summer coincident peaks. This selection "most clearly recognizes cost causation based on the operating, planning and system characteristics of the utility."[20] It must be recognized however, that the only data available for many customers on demand-based rates is the maximum demand during a billing period. Since interval data is not recorded, load research estimates of class contributions are made to develop the necessary allocation information. The reality is that the coincident/non-coincident demand relationship

[19] Response to VSI 2.03.
[20] Ibid.

varies across different types of commercial and industrial customers that generally populate the classes with demand charges. This is an example of an approximation used for convenience.

In sum, the Average and Peaks method is based on the presumption that production and transmission costs are incurred to meet average demand (energy) in part and the four monthly system peak demands in part, generally all production and transmission costs (about 79% of the total) are recovered through a demand charge (if there is one) tied to the individual customer's maximum (non-coincident) peak load each billing period.

Similarly for distribution costs, the vast majority of costs are allocated to customer classes on the basis of non-coincident peaks. Here too, distribution systems are not built to meet the sum total of all customer loads but rather the aggregated load on each circuit. The major benefit of aggregating loads is to capture load diversity – the fact that different customers have differing load characteristics and will experience their peak loads at different times. As a practical matter determining the coincident load contribution to the peak load by circuit would be a monumental task so the NCP method has been generally accepted as a proxy. Again, there are good reasons this method is used, but it should not be assigned any more precision than it deserves. One final point –

distribution costs are mostly rolled together and allocated across all customer classes, regardless of the actual cost of the portion of the distribution system installed and maintained to serve a particular customer - another approximation for convenience and administrative simplicity.

Q. Please summarize the relationships among cost causation, cost allocation, and cost recovery.

A. Keeping in mind that rates are based on what is presumed to be a representative test period in which the relationships will remain somewhat constant between rate cases, the following are the key takeaway points:

- Cost causation: the goal of cost allocation is to assign costs to the broad customer classes based upon the reason that the cost was incurred;
- Use of estimates and approximations: allocation of costs on the basis of class coincident demand is logical from a causation standpoint, but of necessity is based upon estimates of the class demands at the time of the system peak demand;
- Rate design: designing rates for classes containing customers that may be similarly situated, but have some diverse characteristics will create equity issues between those above and below the mean;
- Cost recovery: recovery of costs on a basis other than cost causation can result in cross subsidization within a customer class;

Q. Given these explanations and examples, what is the effect of moving demand related costs to the monthly customer charge?

A. Under current circumstances, there is a limited universe of billing parameters available for recovering costs from small customers such as residential and small commercial – those with only an energy meter. The utility can recover costs on the basis of energy consumed or as a flat fee. Since the nature of the costs TEP seeks to recover through the monthly fee is unspecified, it is not possible at this time to say whether such costs are more closely related to the existence of the customer (would argue for the customer charge recovery) or the size of the customer (would argue for continued energy charge recovery).

Q. Are there other sources of subsidies outside of those inherent in cost allocation and rate design?

A. Yes. For example, rates that promote certain behaviors are often seen as good for the general public as a whole, whether it is using energy more efficiently, encouraging clean generation such as solar and wind, discounting rates to attract businesses to the region, or other special rates for new technologies like electric vehicles. These types of programs can result in individuals paying more or less than their share of the utility's costs allocated to his or her customer class.

Q. With this context, please summarize your concerns about the TEP customer charge proposal.

A. Current recovery methods are well established. TEP has not presented sufficient evidence at this time to justify a departure from existing practices. Moreover, the proposal is inconsistent with the basic principle of recovering costs based on cost causation set forth by TEP, NARUC, and Bonbright. Indeed, TEP is not delineating any particular demand-related costs it believes are appropriate for recovery through the customer charge, but rather proposes that this be the first gradual step towards recovery of all demand-related costs through the customer charge.

Q. What is your recommendation with respect to this issue?

A. I recommend that TEP's proposed change to the Customer Charges as submitted be rejected in this proceeding. However, TEP should be required to submit a report outlining the specific demand-related costs it believes should be recovered through the customer charge, along with narrative support. Through a brief set of workshops, I believe accommodation can be reached on this issue and new tariffs can be filed without the necessity of a comprehensive rate change filing.

Proposed Increase to Monthly Demand Ratchet

Q. Please explain what a demand ratchet is.

A. A ratchet is a minimum bill structure applied to customers that are billed in part on a demand basis. The billing demand for a customer is the greater of the customer's actual demand or a set percentage of its maximum demand over a past period – usually 11 months.

Q. Please describe the TEP demand ratchet proposal.

A. TEP is proposing to increase the demand ratchet for commercial and industrial customers to a uniform 100% of each customer's maximum demand in the prior 11 months. Similar to its proposal to add demand related costs to the customer charge discussed above, TEP justifies this proposal as a means of reducing the costs recovered from high load factor customers:

> *Higher load factor customers will pay less to subsidize lower load factor customer's less efficient use of the utility's system.*[21]

TEP believes the ratchet allows costs to be more equitably recovered from customers within a class with demand charges.[22]

Q. Do you agree with this assertion?

[21] Response to VSI 1.28
[22] Response to VSI 2.26

A. No. A commercial or industrial customer's energy use characteristics (monthly demands and energy consumption) are reflective of the nature of their business operations. Such operations may be very consistent from month to month or may be more seasonal in nature. As discussed in detail in the previous section, a utility's costs of providing service are functionalized, classified, and then allocated to customer classes on the basis of cost causation. TEP assigned its costs to each customer class in this proceeding on the basis it determined best captured the reason for the cost incurrence. To the extent a low load factor customer may have lower loads in some months, and lower energy use, it contributes to fewer costs being allocated to the class as a whole. For the utility to then seek to collect higher costs from customers that have helped reduce the overall class cost burden is inconsistent. Moreover, it provides a double benefit for high load factor customers – first, they receive the benefit of lower overall costs being assigned to their rate class, and second, the unit rates are reduced (and hence their own monthly charges) by increasing the billing parameters for the lower load factor customers.

Q. Does a demand ratchet change the total amount of costs recovered from each customer classes?

A. No. It only changes the amounts each customer within the customer class pays for fixed cost recovery. Because the total level of billing determinants increases, the demand rate is reduced, all else being equal. Within a given rate class, a portion of customers will pay more and a portion will pay less. Either way TEP will recover all of its costs. TEP is trying to reduce the costs to high load factor customers at the expense of lower load factor customers.

By way of a simple example, let's suppose that two commercial customers have the same annual peak load. Customer A however is a high load factor customer running all of its equipment, including HVAC, 24 hours per day, while Customer B's operations are more typical matching the customer class weighted average demand and consumption relationship -- in other words the load factor parameters for which the class rates are actually designed. Thus, under normal *non-ratcheted* demand cost recovery Customer B would pay the demand charges that cost causation, allocation and recovery deem appropriate for its class. Customer A would properly pay more because the designed rates would require a larger revenue contribution based on the approved cost causation and allocation bases. By implementing the ratchet TEP is proposing, both customers would pay the same amount towards fixed cost recovery, resulting in a subsidy of the higher load factor customer by the average load factor customer.

Q. Are there other effects on customers subject to the demand ratchet?

A. Yes. A demand ratchet effectively removes the incentive for the customer to improve the efficiency of its operations and thus reduce its peak demand. In other words, a customer is less likely invest in efficiency or distributed generation if it sees no benefits for a year.

Q. Is this proposal consistent with rate design principles outlined by TEP?

A. No. It is inconsistent with the principle of cost causation as a basis for allocation and cost recovery. It is also inconsistent with another principle TEP witness DesLauriers notes on page 14 of his direct testimony – that of administrative simplicity: "Customers should be able to understand the price signals provided by the bill and respond to those signals efficiently." Clearly, the ratchet does not fulfill this principle, unless the desired response is for the customer to freely demand more and more power up to the point of the highest demand over the past eleven months. Finally, in response to discovery (VSI 1.35), witness DesLauriers notes customers with similar cost profiles paying significantly different bill amounts "is a major problem because it violates the principles of Rate Equity and Non-discrimination and Cost of Service and Rate Efficiency." I submit that the equally important corollary to his point is that customers with significantly <u>different</u> cost profiles paying the <u>same</u> bills also violates these same principles.

Q. What is your recommendation for TEP's proposal to increase its ratchets to 100%?

A. I recommend the Commission reject this proposal in its entirety, based on (1) inconsistency with cost causation and rate design principles, (2) the creation of a new and maximized (by virtue of the 100% feature of the ratchet) cross subsidy within the applicable rate classes, (3) exacerbation of the existing disparity between demands used for allocation and those used for billing, and (4) increasing the disincentive for customers to invest in technologies that can reduce demand.

Proposed Lost Fixed Cost Recovery Mechanism (LFCR)

Q. Please describe the TEP LFCR proposal.

A. The TEP LFCR proposal is a decoupling mechanism limited in scope that keeps the utility revenues whole with respect to reductions in sales related to two specific programs – energy efficiency and distributed generation.[23]

Q. How does the LFCR proposal work?

A. In short, TEP estimates the lost revenue associated with sales reductions related to these two programs and develops a rate rider to recover these amounts from all customers.

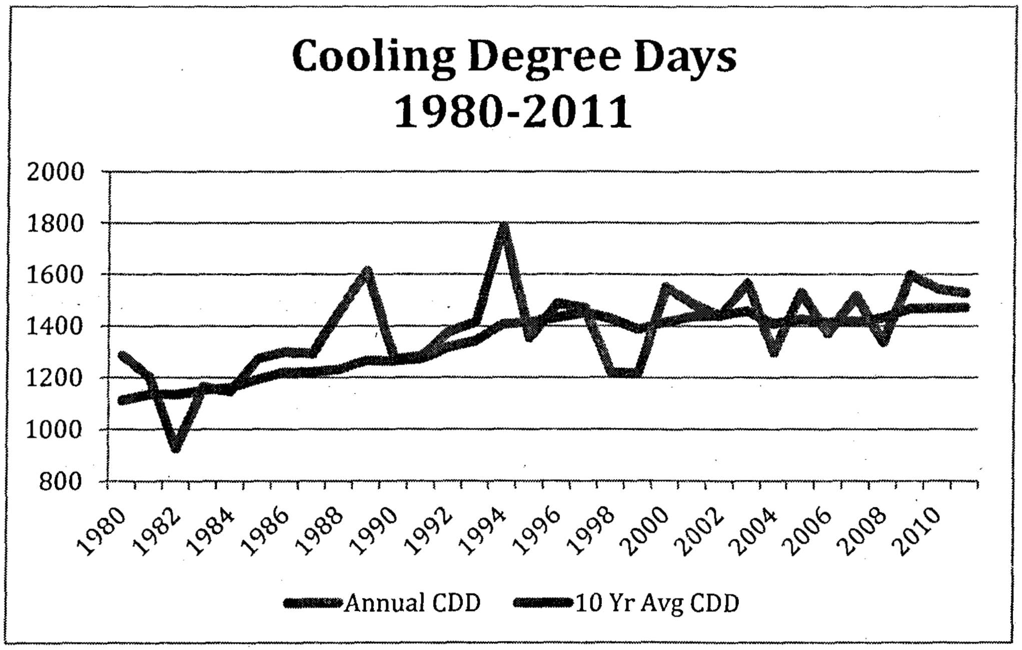
Q. Do you agree with the principles behind the LFCR?

A. I think a mechanism such as this could be helpful to address TEP's concerns about the volatility of revenue related to fluctuating sales levels. However, I do have concerns about this proposal, in particular the focus on EE and DG as the sole sources of sales changes addressed by the LFCR, and the demand component of the calculation of lost revenue.

[23] TEP states in response to VSI 2.40 that it views distributed generation or DG programs as synonymous with net metering programs but the mechanism is intended to be inclusive of both DG and net metering.

Q. Please describe the concerns you have with respect to the sources of sales effects.

A. As described in the opening section of this testimony, sales can fluctuate up and down for a variety of reasons. A relevant example is the increase in test year sales due to warmer than normal weather described by TEP in its "weather normalization" adjustment. The adjustment reduces test year sales to eliminate the impact of the warmer than normal 2011 summer. However, the cooling degree data provided by TEP in response to VSI 2.55 appears to show 2011 as part of a long-term trend, and not an aberration.



As noted by TEP witness Jones on page 9 of his direct testimony, the weather normalization adjustment is a negative $7,573,805, translating to an *increase* in revenue requirements of about $12 million, after grossing up for income taxes. In other words, had 2011 weather been equal to the ten year trend, electricity sales would have been lower. This adjustment finds that the additional sales resulting from non-normal weather is the same order of magnitude as the cumulative sales effects of energy efficiency programs and DG programs for which TEP seeks recovery of lost revenue.

Q. Are you taking issue with the determination of inclusion of the weather normalization adjustment?

A. Not at all. I am suggesting that other conditions can affect sales as much as those for which TEP seeks to account. We simply don't know what the weather will be in the future, and time will tell how much "more extreme than normal" the weather in 2011 actually was, but cooling degree data appears to show a trend. This uncertainty can be addressed by inclusion of a weather normalization sales adjustment in the LFCR mechanism. Note that weather normalization sales adjustments can work in both directions – adding sales in cooler than normal years or reducing sales in warmer ones.

Q. In addition to the weather normalization issue you previously discussed, do you have any concerns about the mechanics of the LFCR mechanism?

A. Yes, I do have a concern about one additional element of the LFCR. In a nutshell, the LFCR tries to isolate the rate component for each applicable rate class that recovers the utility's fixed costs. For example, TEP's view is that all costs recovered through the residential rate class energy charge are fixed, since it proposes to move fuel costs fully into the PPFAC mechanism. Thus TEP believes the revenue associated with every kWh of residential sales reduction related to EE or DG represents a loss to fixed cost recovery. Given TEP's assumptions about fixed and variable costs, I don't disagree with this perspective.

However, the rates for larger customers that include a demand charge are treated somewhat differently. Because the demand charge for these classes recovers the assigned fixed costs, a loss in fixed cost recovery only occurs if there is some reduction to the demand-based revenues that the commercial solar customer (or commercial energy efficiency program participant) provides. For example, if the commercial customer generally experiences its peak demand at night, then there would be no loss in fixed cost recovery related to the solar system. If the commercial solar customer's peak occurs each day coincident with the solar generation peak and there is never any cloud cover at that time, then the customer's demand revenue will be reduced. Since commercial customers are not homogeneous and the degree to which a DG solar system will offset demand charges will vary greatly, an assumption must be made regarding how much the demand charge is reduced for every kW installed, and in turn for every kWh of sales reduction, for commercial solar customers.

Q. Has TEP made such an assumption?

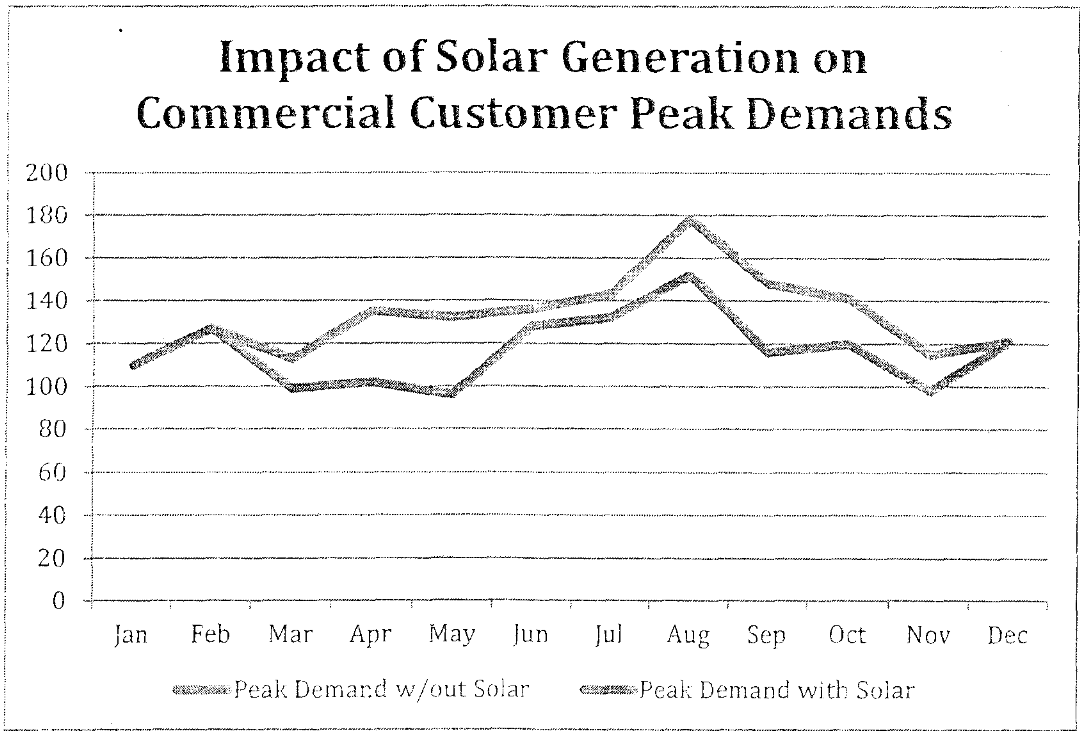
A. Yes. The LFCR mechanism implicitly assumes that half (50%) of the demand-based revenues will not be recovered from commercial customers with solar generation, and proposes to recover these revenues through the mechanism. However, there is no analysis or supporting evidentiary material to back this amount up. Indeed, TEP explicitly said that it does not believe that EE and DG programs reduce individual customer peak demands by one-half.[24]

Q. Does 50% seem like a reasonable figure?

A. No, it doesn't. The proper way to determine any demand charge-related revenue reduction associated with DG or EE programs is to analyze a representative sampling of such customers over an extended period of time. To my knowledge this has not been performed by any Arizona utility. The only Arizona-specific information of which I'm aware is a recent summary report addressing net metering submitted to the Commission on December 6, 2012 by Arizona Public Service in its Renewable Energy Standard (Docket Nos. E-01345A-10-0394 and E-01345A-12-0290). While it is a hypothetical example, Table 10 in Appendix B delineates the demand charge reductions for a commercial customer assuming a solar installation that matches its peak load of 178 kW.

[24] Response to VSI 2.49

Month	Peak kW Demand w/out Solar	Peak kW Demand with Solar	Solar Impact on Peak - kW	% of Solar System Size
Jan	110	110	0	0%
Feb	127	127	0	0%
Mar	113	99	14	8%
Apr	135	102	33	19%
May	132	96	36	20%
Jun	136	128	8	4%
Jul	143	132	11	6%
Aug	178	152	26	15%
Sep	148	116	32	18%
Oct	141	120	21	12%
Nov	115	98	17	10%
Dec	121	121	0	0%
		Average kW Reduction	**16.5**	**9%**



The results show that on average demand charges would be reduced by only 9% of the capacity of the on-site solar generation. Thus, the 50% assumption proposed by TEP appears to be vastly overstated and should not go into effect.

Q. Are there fuel cost savings realized by all customers?

A. Yes. As fuel is a cost passed directly through to consumers, savings related to fuel costs will inure to the benefit of all customers frequently - whenever the PPFAC is updated. Moreover, as generation is typically dispatched on an economic basis, a kWh saved by a retail customer reduces <u>marginal</u> generation requirements by some 1.1kWh, accounting for losses. Marginal generation costs typically are burning the most expensive fuel of all resources on line. Thus, depending on the fuel mix, the savings generated by the sales reduction is often 10-40% higher than the average cost of fuel.

Q. Do you have other comments regarding the LFCR?

A. Yes. It is important to acknowledge that there are costs other than fuel that are <u>avoided</u> as a result of energy efficiency and distributed generation programs. The LFCR mechanism only addresses the revenue side of the equation related to non-fuel costs.

Q. Are you suggesting that there are fixed costs in TEP's cost of service soon to be embedded in rates that are avoided by the EE and DG programs?

A. No. The test year costs are for the most part sunk and cannot be "put back in the bottle." However, as TEP itself notes, "DSM programs will reduce TEP's annual energy requirements by approximately 1,700 GWh in 2020, scaling back that year's system peak demand by 325 MW. But for those programs, TEP would be evaluating the need for another new power plant or finding another source for that energy."[25] The savings to customers are not insignificant – about $430 million in capital costs including the transmission interconnection.[26]

Additionally, there have been a number of recent studies that have found avoided cost benefits related to DG. A review of several studies was conducted by the Solar America Board for Codes and Standards[27] in a report entitled "A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering" released early in 2012. The report reviews and synthesizes three studies performed for major utilities in Arizona, California, and Texas. While the analysis and results of the studies are utility specific, the methodology can be generalized and inform reviews of benefits and costs of distributed solar resources elsewhere. The report suggests the following benefits are provided by DG:

[25] Direct testimony of TEP witness Bonavia, page 14.
[26] Response to VSI 1.16.
[27] See http://www.solarabcs.org/current-issues/interconnection.html

Benefits to the Utility
Avoided Energy Purchases (inc/fuel)
Avoided T&D line losses
Avoided Capacity Purchases
Avoided T&D Investments and O&M
Environmental Benefits – NO_x, SO_x, PM, & CO_2
Natural Gas Market Price Impacts
Avoided RPS Generation Purchases
Reliability Benefits

Q. Are these benefits available to the utility immediately upon deployment of distributed generation?

A Yes. The benefits exist as soon as the DG is installed and operating, however some of the costs will not be immediately avoided. For example, there are capacity benefits that exist right away, but actual cost savings such as those identified by TEP related to DSM, may not be realized until a new plant is actually avoided. It is possible however that such capacity benefits could be realized much sooner if there are purchased capacity costs that can be avoided.

Q. How significant is the capacity benefit provided by solar resources in Arizona?

A. There are two steps to determining the capacity benefits. First is determining how much of the solar capacity can be relied upon to help the utility meet its system peak. The second step incorporates the current capacity situation of the utility and how the available solar capacity can impact its resource plan. There is some information available on the former issue, however I have not engaged in the

TEP resource planning process and cannot take a position with respect to the opportunities for utility capacity cost reductions, other than relying upon the testimony of Mr. Bonavia.

With respect to the determination of the portion of solar capacity that can be counted upon for meeting utility system peak loads, the National Renewable Energy Laboratory released a report[28] in June 2006, reviewing effective load carrying capability (ELCC) analyses and estimating statewide ELCCs for each state. The report includes a comparison of the results of solar capacity analyses performed in the early 90s with similar studies performed in the 2002-03 time frame that include additional data. Tucson Electric Power, Arizona Public Service and Salt River Project are three of the 39 utilities reviewed. All three Arizona utilities were found to have ELCCs for a two axis tracking solar resource (with low penetration) of about 70%. The report also estimated statewide ELCC results for Arizona assuming several penetration levels for several different solar resource configurations, two of which are repeated here:

Installation Geometry	Capacity Value at 2% Penetration	Capacity Value at 5% Penetration
2-axis Tracking	71%	68%
Horizontal	55%	52%
South 30° tilt	57%	54%
Southwest 30° tilt	65%	61%

[28] Perez, Margolis, et al., *Update: Effective Load-Carrying Capability of Photovoltaics in the United States*, Conference Paper NREL/CP-620-40068, June 2006.

Note that increasing penetration levels of solar resources reduce the capacity value as the system peak load is shifted later in the day. This chart indicates in all cases that at least half of the solar capacity installed can reliably contribute to the capacity needed by the utilities to serve peak loads. This significant value for solar resources is provided to the grid by virtue of the installations and all customers will receive these benefits over time as they impact the resource planning of the utility.

The takeaway point is that solar contributes value and even the potential for fixed cost reduction. These solar values will offset additional costs that are being recovered from non-participants in the solar programs.

Q. Please summarize your recommendations regarding the LFCR?

A. The non-fuel benefits generated by distributed solar will accrue over time to all ratepayers of the utility. However calculating some of these benefits can be complex and is not without controversy. Thus in my view, TEP's LFCR approach provides a reasonable balance of interests and administrative efficiency. That said, there are two changes to the mechanism that should be made:

1. Include an adjustment to account for "non-normal" weather related sales, based on cooling degree days; and

2. Either eliminate the adjustment for demand charge revenue impacts altogether, or include an appropriate level of demand charge revenue impact based upon a thorough analysis of a representative sampling of such customers over an extended period of time.

Q. Do you have any other comments related to this issue?

A. Yes. The recommendation I have just outlined is sufficient to capture the revenue effects of sales changes largely out of the control of TEP. However, as noted at the beginning of this testimony, the impacts of economic conditions can far outweigh the effects of efficiency and solar programs, and weather combined. As such, Vote Solar would also find a full decoupling approach acceptable, provided the demand charge matter herein discussed is properly addressed.

Q. Please summarize your recommendations in this proceeding.

A. Utilities across the country including TEP have experienced major changes and shifts in the historically stable business. As a result utilities are seeking incremental changes in certain aspects of their business model. In this proceeding, TEP is proposing a number of structural changes to its retail rates in an effort reduce the uncertainty and improve the stability of revenue recovery related to electric sales. In this testimony I have addressed three of those changes.

1. Customer Charges: I recommend that TEP's proposed change to the Customer Charges as submitted be rejected in this proceeding. However, TEP should submit support for specific costs to be recovered through the customer charge, and a limited stakeholder process should ensue to reach accommodation.
2. Demand Ratchet: I recommend the Commission reject this proposal in its entirety for the reasons described above.
3. Lost Fixed Cost Recovery: With the two changes below, TEP's LFCR approach provides a reasonable balance of interests and administrative efficiency.
   a) Adjust sales to account for "non-normal" weather; and
   b) Eliminate the adjustment for demand charge revenue impacts. In the alternative, include an appropriate level of demand charge revenue impact based upon a thorough analysis of a representative sampling of such customers over an extended period of time.

Finally, as an alternative to the TEP proposed LFCR mechanism, a full decoupling approach could be considered, and would have our support.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Rick Gilliam

January 2012 to Present: Director of Research and Analysis, the Vote Solar Initiative, San Francisco, CA. Manages the technical and policy research for Vote Solar, and engages in state, regional, and national campaigns related to key solar market policies.

January 2007 to January 2012: Vice President, Government Affairs, Sun Edison, LLC, Beltsville, MD. Directs and manages policy development and implementation for the Americas at the regulatory and legislative levels. (Promoted from *Managing Director* June '09 and from *Director* Sept '07)

Dec 1994 to Jan 2007: Senior Energy Policy Advisor, Western Resource Advocates (formerly the Land and Water Fund of the Rockies), Boulder, Colorado. Develop innovative clean energy and air quality public policies within the economic and cultural framework unique to this region. Lead environmental advocate in development of Arizona Environmental Portfolio Standard, Nevada Renewable Portfolio Standard implementation rules, Colorado Renewable Energy Standard legislative proposals, and the 2003 Utah Renewable Energy Standard legislative proposal. Principal author of Colorado's Amendment 37 and lead advocate for related PUC rule development.

Jan 1983 to Dec 1994: Director of Revenue Requirements, Public Service Company of Colorado, Denver, Colorado. Primary responsibility for development of formal rate-related filings for this investor-owned utility for electric, gas, and thermal energy service in two states and the FERC. Developed and responded to a variety of proposed mechanisms to encourage the use of energy efficiency technologies, including innovative rate design approaches.

Dec 1976 to Dec 1982: Technical Witness (Engineer), Federal Energy Regulatory Commission, Washington, D.C. Testified as expert witness on behalf of the FERC in wholesale rate filings on technical, accounting, and economic issues related to rate design, pricing, and other issues.

A. Education

Masters, Environmental Policy and Management, University of Denver, Denver, Colorado

Bachelor of Science, Electrical Engineering, Rensselaer Polytechnic Institute, Troy, New York

B. Related Publications

Gilliam and Baker, "Green Power to the People," *Solar Today*, July/August 2006.

Dalton & Gilliam, "Walking on Sunshine: Energy Independence on the Rez," *Orion Afield*, Summer, 2002.

Gilliam, Rick, "Revisiting the Winning of the West," *Bulletin of Science, Technology & Society*, April 2002.

Blank, Gilliam, and Wellinghoff, "Breaking Up Is Not So Hard To Do: A Disaggregation Proposal," *The Electricity Journal*, May 1996.

Summary of Formal Testimonies available upon request